S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter, on the Commission's own motion, establishing the method and avoided cost calculation for **CONSUMERS ENERGY COMPANY** to fully comply with the Public Utilities Regulatory Policy Act of 1978, 16 USC 2601 et seq.	)	Case No. U-18090

NOTICE OF PROPOSAL FOR DECISION

The attached Proposal for Decision is being issued and served on all parties of record in the above matter on March 10, 2017.

Exceptions, if any, must be filed with the Michigan Public Service Commission, 7109 West Saginaw, Lansing, Michigan 48917, and served on all other parties of record on or before March 24, 2017, or within such further period as may be authorized for filing exceptions. If exceptions are filed, replies thereto may be filed on or before April 7, 2017. **The Commission has selected this case for participation in its Paperless Electronic Filings Program. No paper documents will be required to be filed in this case.**

At the expiration of the period for filing exceptions, an Order of the Commission will be issued in conformity with the attached Proposal for Decision and will become effective unless exceptions are filed seasonably or unless the Proposal for Decision is reviewed by action of the Commission. To be seasonably filed, exceptions must reach the Commission on or before the date they are due.

MICHIGAN ADMINISTRATIVE HEARING SYSTEM
For the Michigan Public Service Commission

Mark E. Cummins

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Mark E. Cummins
Administrative Law Judge

March 10, 2017
Lansing, Michigan

STATE OF MICHIGAN

MICHIGAN ADMINISTRATIVE HEARING SYSTEM

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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PROPOSAL FOR DECISION

I.

OVERVIEW AND HISTORY OF PROCEEDINGS

In 1978, Congress enacted the Public Utilities Regulatory Policy Act (PURPA), in an attempt to encourage the development of renewable electric energy sources, including cogeneration, to increase America's energy independence as well as reduce its reliance on fossil fuels, and to hopefully lead to a larger amount of dispersed generation. In apparent recognition that the basic incentive structure for utilities would be unlikely to result in the development of these forms of alternative energy production (e.g., utility profits, and thus the companies' return on investment, are largely based on their own generation of electricity), PURPA demanded that utilities purchase energy and capacity from qualifying facilities (QFs) within their service territories. Moreover, PURPA required that utilities do so at the full cost that they did not incur as a result of those purchases, which is generally referred to as the respective utility's avoided cost. As such, the overall intent of PURPA's passage was to: (1) combat a utility's logical preference to self-generate its electricity; (2) remove barriers for non-utility generation where such external energy generation was cost-effective; (3) allow customers to benefit from a broader diversity of energy resources at no higher cost to the utility than would otherwise be incurred; and (4) let customers and society as a whole benefit from increased energy independence, more use of renewable energy sources, a higher level of dispersed energy production, and added cogeneration.

In so doing, PURPA delegated to the various state commissions the task of setting the appropriate levels of full avoided cost (covering both energy and capacity) for the utilities within their jurisdiction. In Michigan, this was initially done in the context of Case No. U-6798 and related proceedings, in which orders were issued from the early 1980's into the 1990's. The earliest of these orders dictated that utilities purchase electricity from QFs at the utility's respective avoided cost, provide standby service to those QFs as needed, allow for the interconnection of the QFs to the utility's transmission and distribution systems, and make various data filings. <u>See</u>, the Commission's March 17, 1981 order in Case No. U-6798. By way of an order issued in that docket on August 27, 1982, the Commission approved a series of settlement agreements between QFs and the local utilities which relied on various avoided cost methodologies.

Subsequently, a significant legal dispute arose concerning Consumers Energy Company's (Consumers) avoided cost calculation as it related to a very large gas-fired cogeneration facility -- the Midland Cogeneration Venture -- which was docketed as Case No. U-8871. A consolidated case involving over 40 QFs and their issues relating to

Consumers was conducted in that docket, resulting in the issuance of 20 orders between 1987 and 1993. The outcome of those orders was the approval of many contracts between Consumers and various QFs (33 of which still exist) with rates generally based on the avoided cost of a proxy coal plant. In addition, Michigan enacted laws (such as Act 81 of 1987, MCL 460.6j, and Act 2 of 1989, MCL460.6o), clarifying the way in which PURPA was to be implemented in the state.[1]

Because (1) several PURPA contracts were approaching their initial expiration dates, (2) new QFs were inquiring about avoided cost rates and other factors related to PURPA, and (3) significant changes have taken place in the energy industry over the 20 years since it last considered avoided cost methodologies [most recently, the significant drop in the price of natural gas], the Commission issued an order starting an investigation into the matter. See, the Commission's October 27, 2015 order in Case No. U-17973 (the October 27 order). Specifically, it directed the Commission Staff (Staff) to convene a working group including a broad range of stakeholders to research and analyze the structure and pricing that should now be applied to QF/utility agreements and operations. This group, called the "PURPA Technical Advisory Committee" (and generally referred to as the TAC), met five times between December 2015 and March 2016. Thereafter, the Staff issued a report on April 8, 2016 (the TAC Report) providing recommendations based on what it concluded were the best practices for cost computation and contract

[1] Subsequently, by way of the Energy Policy Act of 2005, PL 109-58, 119 Stat 594, the Federal government gave utilities the right to terminate their mandatory purchase obligations if QFs have non-discriminatory access to completive markets. With regard to Consumers, this provision led the Federal Energy Regulatory Commission (FERC) to relieve the utility, as of January 25, 2012, of its requirement to enter into any new purchase agreements with QFs having a net capacity of greater than 20 megawatts (MW).

issues related to the implementation of PURPA in Michigan. Among other things, the TAC Report suggested researching avoided cost methodologies and initiating a Commission-led process for determining Michigan utilities' respective avoided costs for PURPA projects rated at 20 MW or less. See, Exhibit S-5.

Following up on the suggestions contained in the TAC Report, the Commission issued orders on May 3, 2016 in various dockets requiring utilities, including Consumers, to file testimony and/or exhibits supporting what they felt to be the best avoided cost methodologies to be used, as well as the resulting avoided costs to be applied to PURPA projects in their service territories that had a capacity of 20 MW or less. Specifically, the Commission directed Consumers to provide avoided cost calculations using (1) the hybrid proxy plant method suggested by the Staff in the TAC report, (2) the transfer price methodology that was also discussed in that report, and (3) any other method that the utility would suggest. See, the Commission's May 3, 2016 order in Case No. U-18090 (the May 3 order). Finally, Consumers was ordered to submit "proposed standard rate tariffs, including applicable design capacity" for its existing and potential QFs.[2] See, Id., p. 4.

As directed in the May 3 order, and pursuant to due notice, a prehearing conference was held in the present docket (Case No. U-18090) on July 21, 2016, before Administrative Law Judge Mark E. Cummins (ALJ). In addition to Consumers and the Staff, several potential intervenors also filed appearances and participated at the

[2] Pursuant to Federal Rule--specifically, 18 CFR 292.304(c)(1) and (2)--electric utilities are required to have standard rates covering all purchases from QFs having a design capacity of 100 kilowatts (kW) or less. However, according to those rules, the standard rate may be extended to generating facilities with capacity in excess of 100 kW.

prehearing. Intervention was granted on that date to the following parties: the Independent Power Producers Coalition of Michigan (IPPC); the Great Lakes Renewable Energy Association (GLREA); the Environmental Law & Policy Center, Ecology Center, Solar Energy Industries Association, and Vote Solar (collectively, the ELPC); Cadillac Renewable Energy, LLC, Genesee Power Station Limited Partnership, Grayling Generating Station Limited Partnership, and T.E.S. Filer City Station Limited Partnership (collectively, Cadillac); the Michigan Environmental Council; and Michigan Power Limited Partnership and Ada Cogeneration Limited Partnership (collectively, MPLP). In the course of that prehearing, a consensus schedule was established for use in this particular case.

Pursuant to that schedule, Consumers, the Staff, and the Intervenors filed testimony and exhibits supporting their various positions. Following discovery and the filing of rebuttal testimony, evidentiary hearings were conducted on December 8, 2016. A total of 19 witnesses were offered at that time, 6 on behalf of Consumers, 3 on behalf of the Staff, 5 by IPPC, 4 in support of ELPC, and 1 by GLREA. Overall, the record assembled in this matter consists of two volumes of transcript totaling 528 pages and 71 exhibits.

Consistent with the agreed-upon schedule (as amended), initial briefs were filed by Consumers, the Staff, IPPC, ELPC, GLREA, Cadillac, and MPLP on January 13, 2017. Likewise, reply briefs were submitted by Consumers, the Staff, IPPC, ELPC, and GLREA on February 9, 2017.

II.

POSITIONS OF THE PARTIES

In the section that follows, this Proposal for Decision (PFD) will describe the various positions offered by the parties, detail their evidence, and discuss their respective suggestions for the Commission's resolution of the issues raised in this case.

A. Consumers

Through the six witnesses presented by Consumers in this matter, the utility initially proposed an avoided cost methodology that was based on a four-tier approach, with each tier defined by the utility's capacity need in any given year. See, 2 Tr. 408. Specifically, the first tier assumed that no capacity was needed, and thus suggested paying nothing for capacity supplied by a QF, and only paying for energy delivered by a QF at either the actual or forecasted locational marginal price (LMP). See, 2 Tr. 409. The second tier, which would have been used for situations where the company's capacity needs were above zero but "less than 200 Zonal Resource Credits (ZRCs)," would pay QFs for capacity at a price equal to the Midcontinent Independent System Operator's (MISO) Planning Resource Auction (PRA) rate, and again pay for energy delivered at either the actual or forecasted LMP. See, Id. The third tier, which would come into play when a planning period showed a capacity need of between 200 and 1,000 ZRCs--and where Consumers claimed it would consider building a natural gas-fired combustion turbine (NGCT)--called for a capacity payment equal to the "Economic Carrying Charge fixed cost of a NGCT," as well as an energy payment equal to "the lesser of the actual or forecasted LPM," on the one hand, or "the incremental cost of production of the NGCT," on the other. Consumers' initial brief, p. 4, citing 2 Tr. 410.

The fourth and final tier initially proposed by the utility, applicable to situations where the company's plans showed a need greater than 1,000 ZRCs, was essentially the same as the third, with the exception that the capacity and energy payments would be based on the avoided cost of a natural gas-fired combined cycle (NGCC) plant, as opposed to a NGCT facility. See, Id.

As for the "standard offer tariff" that the Commission required Consumers to submit for potential use by the smaller QFs in its service territory (which would allow them to avoid negotiating specific contract terms with the company), the utility initially advocated applying the same four-tier avoided cost structure described above, but offering the tariff to only those QFs that are sized at 100 kW or less, and limiting the length of the standard offer agreement to a maximum of 5 years. See, Id., pp. 5-6, citing 2 Tr. 311-312. According to the company, the 100 kW cap was (1) "consistent with the federal regulations implementing PURPA," which do not "require" making standard offers available to QFs larger than 100 kW, (2) recognizes that QFs larger than 100 kW may "have the experience and resources to negotiate" an individually-designed contract, and (3) reduces the chance that the utility's capacity need "would be oversupplied" before the company's need could be re-evaluated. Id., p. 6. Regarding the proposed 5-year limit on such agreements, Consumers asserted that the term was selected because:

> It provides a compromise between the need by QFs for a longer term and the need for protection of the Company's electric customers from significant deviations between estimated avoided costs and actual avoided costs.

Id., p. 5, citing 2 Tr. 311.

Nevertheless, through its initial and reply briefs, Consumers presented a different structure, which was based--in significant part--on the Staff's proposals regarding avoided costs and the standard contract. Specifically, the utility now contends that the capacity component of its avoided cost should be "based on the levelized fixed cost of a NGCC plant," and that the energy component should be either:

> (i) the lesser of the forecasted LMP or forecasted variable cost of a NGCC plant, or (ii) the lesser of the actual LMP or the variable cost, where actual or forecasted energy price compensation is per the choice of the QF.

Consumers' initial brief, p. 9, citing 2 Tr. 417; <u>See</u> <u>also</u>, Consumers' reply brief, pp. 8-14. In this regard, the utility notes that its revised proposal is not only "based on the Staff's modified proxy plant methodology," but is also "similar to the avoided cost methodology" that DTE Electric Company has proposed in its corresponding (and ongoing) avoided cost proceeding in Case No. U-18091. <u>Id</u>., p. 9.

Moreover, the company now agrees with the Staff that its capacity needs should be considered over the company's 10-year planning horizon, which would provide the Commission and the parties to this case with "the ability to forecast the capacity need of the utility during the particular timeframe." <u>Id</u>. However, it continues:

> Under [Consumers'] revised proposal, if there is a need for capacity within the first five years of the Company's ten-year planning horizon, QFs should be paid for capacity at the levelized fixed cost of a NGCC facility. Otherwise, QFs should be paid for their capacity at the capacity cost established by MISO in its annual PRA. This is due to the fact that it is unreasonable for the Company to make capacity payments to QFs beginning in year one of the ten-year planning horizon if the Company does not show a capacity need until year nine or ten. Moreover, while a showing of capacity need nine or ten years into the future may justify some preliminary activities (e.g., the securing of air permits), forecasts that far out can be fairly unpredictable. A more prudent approach would reserve material commitments to a demonstrated capacity need until a point in time where the need becomes more certain. As [Priya D. Thyagarajan, the head of Consumers' Electric Supply Planning Section] testified, the Company considers "… five years as the period over which we would make definitive capacity decisions." Thus, it is reasonable to base the capacity payment on the first five years, as this is the period over which the Company makes its capacity decisions.

Id., pp. 9-10; See also, Consumers' reply brief, pp. 10-11 [citations omitted]. As a result, while essentially concluding that the planning period for capacity needs should look ten years into the future, the utility's actual capacity payments should only be based on the first five years. See, Id., p. 11.

Concerning the issue of energy payments to be made to QFs in its service territory, Consumers continued to assert that QFs should be required to specifically elect at the inception of their respective purchase power agreements (PPAs) to be paid at either (1) the lower of forecasted LMP and the forecasted variable energy cost of a NGCC facility, or (2) the lower of actual LMP and the actual variable energy cost of a NGCC plant. See, Id. This structure should, according to the utility, be applied to both QFs providing service under the standard offer and those negotiating separate PPAs, and (in opposition to the Staff's recommendation) not be "levelized over the term of the contract," which the company asserts would lead to a situation where payments to QFs are "front-loaded." Id.

Turning to the matter of whether other avoided costs--such as those related to reduced transmission expense, line loss mitigation, hedging value, avoided emissions, and lessened environmental compliance costs arising from the receipt of QF-produced power--should be considered, Consumers agreed with other parties that they should be recognized in the computation and implementation of avoided cost payments. See, Id., pp. 11-12. Nevertheless, it applied three caveats to that agreement. First, the utility stated that consideration of those factors should only occur "to the extent that such costs can be directly quantified and actual costs can be directly calculated," as opposed to where such costs are simply "theoretical or merely possible." Id., p. 12. Second, the company asserted that "the reverse should also be true," and that whenever quantifiable increases in expenses related to line losses, hedging, emissions, or environmental compliance might arise from the mandated receipt of electricity from a particular QF, that QF should "reimburse customers for such costs." Id. Third, Consumers argued that all renewable energy credits (RECs) arising from the QFs' electric production should be considered "part of the value that the Company is purchasing from a QF and should be owned by the utility." Id., p. 13. In support of this argument, the utility asserted that:

> RECs are used to comply with Michigan's renewable energy portfolio standards and are a part of the value that the Company is purchasing from a QF. The Company is required to purchase energy and capacity, if needed, from QFs because the energy being produced is renewable and the environmental benefits represented by RECs were being provided to [Consumers'] customers long before the concept of RECs existed. Therefore, customers should not now have to pay extra for these benefits and the RECs should not be separated from the energy and capacity being purchased.

Id.; citations omitted.

Also, with regard to the standard offer tariff, Consumers recommends that it be capped at QFs offering 1.5 MW or less of capacity and energy (which, it contends, should be adequate to accommodate most of its smaller QFs, including most, if not all, of its hydro plants). According to the utility, a cap of 1.5 MW should be "large enough to capture the smaller developers that lack the resources and experience" of larger developers that "are of a size that tends to have contracting needs that are not capable of being standardized," such as special metering arrangements or the ability to relocate. Id. Moreover, it notes that, as described earlier, the company's standard offer would allow QFs to choose between actual or forecasted energy prices. See, Id. However, it points out that any QF electing to use "actual energy pricing" would be eligible for a

10-year contract, whereas those choosing "to be paid on the basis of forecasted energy prices" would have their contracts' terms limited to five-years, thus protecting ratepayers from "the unpredictable nature of forecasted energy prices." Id., pp. 13-14. An exception would be made, the utility continues, "for QFs that prefer forecasted energy pricing," but who are also "willing to accept an updated energy price forecast at the end of year five of the contract." Id., p. 14.

Finally, Consumers proposed that, under its standard offer: (1) capacity payments should be based on its revised avoided cost methodology which, as stated above, is tied to the levelized cost of a NGCC plant; (2) QFs who elect to do so could be paid for capacity based at the MISO PRA level; and (3) pricing for any ten-year contract based on the MISO PRA should be updated if, during the first five years of the utility's 10-year planning horizon, the company shows a need for electric capacity. See, Id. According to Consumers, allowing for the use of the updated NGCC capacity rate at that point could benefit QFs. See, Id. In addition, the utility now suggests providing a line loss mitigation credit to its QFs of 2.37%, which is "consistent with the Company's approach for its Solar Gardens Program." Id., citing 2 Tr. 358. Lastly, Consumers expressed agreement with the Staff's suggestion that all RECs be transferred to the utility when QFs make use of the standard offer tariff. See, Id., p. 15.

Overall, it appears that Consumers' position has moved, both to the utility's credit (likely as a means of diffusing highly-charged issues that have arisen in this case) and to a fairly significant degree, toward the positions proposed by the Staff and other intervenors.

B. Staff

The Staff offered testimony and exhibits from three witnesses, Julie K. Baldwin, Jesse J. Harlow, and Kevin S. Krause, all of which work in the Commission's Electric Reliability Division. These witnesses suggest that the Commission adopt the "proxy unit methodology for capacity and market based pricing methodology for energy" that the Staff ultimately suggested in the TAC Report. Staff's initial brief, p. 4.

Specifically, the Staff recommends using the avoided cost of a NGCT as the basis for Consumers' capacity payments to QFs located within its service territory (because, as noted by Mr. Harlow, they are "relatively quick to build," tend to be "less costly" than other generating facilities, and are "designed to cycle on and off" as needed by the utility). Id., p. 4, citing 2 Tr. 160. In so doing, the Staff also acknowledged the appropriateness of considering the effect of the ZRCs used by MISO to evaluate the utility's capacity needs, as initially discussed by the company. See, Id. The Staff went on to assert that, if Consumers "needs *any* capacity over a 10 year planning horizon," the company "should pay a QF for its capacity." Id. However, the Staff went on to suggest that existing QFs on Consumers' system be treated differently from new QFs, at least with regard to capacity payments, in that any contracts that are renewed would include a capacity payment at "the full standard rate [for] capacity (not the PRA) regardless of whether the company has a need for capacity" during the "10 year planning horizon" set forth in PURPA. Id., p. 5, citing 2 Tr. 157.[3] For new QFs, the Staff continued, capacity payments

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[3] According to Mr. Harlow, the reason for allowing QFs with existing contracts to be compensated for capacity under the Staff's modified proxy plant methodology upon renewal of their contracts with Consumers is that the capacity they provide has already been taken into account by the utility when assessing its future needs. See, 2 Tr. 157.

would simply be set at the PRA "if Consumers' capacity need over the 10 year planning period is fully met." Id.

As for payments for energy provided to the utility, the Staff recommends that all QFs be provided with their choice of the following three options: (1) application of the actual/existing LMP; (2) use of a forecasted LMP over the term of the contract; or (3) a proxy price based on the forecasted variable cost of a NGCC.[4] Each of those three options would also include "the fixed investment cost attributable to energy (ICE)" based on the average investment needed for a NGCT. Id., p. 6. According to the Staff, the rationale behind the added ICE component is that "to benefit from the cheaper energy costs of an NGCC," the difference between the capital costs of building a NGCT as opposed to a NGCC "should be accounted for in the avoided cost model." Id., citing Exhibit S-6. This differential, the Staff states, would then be paid on a volumetric basis and added to the energy payment made to the QFs. See, Id. The above-stated recommendations, the Staff went on to clarify, would only apply to QFs that produce 20 MW or less of electricity. See, Id.

With regard to Consumers' standard contract offer tariff, the Staff suggested several revisions to the utility's proposal, which are shown on Exhibit S-1. These potential revisions include: (1) slightly increasing Consumers' currently-proposed 1.5 MW limit to 2 MW, at least to start, and also adopting a methodology to establish a standard offer size cap in the future based on the amount and timing of the company's

[4] According to the Staff, the reason that it chose the use of a NGCC over a NGCT (which it recommended earlier in regard to the suggested capacity price) for this particular energy cost option was that "utilities are increasingly choosing to build an NGCC due to its efficient use of natural gas." Id., p. 6. According to the Staff, a NGCC would generally be built to supply cheap energy, whereas a NGCT would likely be built to provide cheap capacity. Id., citing Exhibit S-7.

future capacity needs[5]; (2) allowing QFs supplying capacity and energy via a standard contract to select a contract length of either 5, 10, or 15 years; (3) providing the QFs with line loss savings credits based upon their respective locations on Consumers' distribution system; (4) extending the same three energy payment options set forth above to all of the relatively small QFs; (5) also letting QFs using the standard offer tariff to rely on the Staff's capacity cost calculation methodology as testified to by Mr. Harlow and described earlier; (6) generally transferring the RECs to the utility, but leaving the ownership of RECs to be negotiated by the parties in situations not involving a standard offer agreement; (7) reviewing the standard offer tariff every two years as part of the avoided cost biennial review process; (8) allowing standard offer agreements to be reviewed and approved on an ex parte basis; and (9) as a safeguard to both Consumers and its ratepayers, directing the utility to file a case requesting a reduction in the standard offer pricing to a level coinciding with the PRA, but only if and when the company's 10-year capacity-related planning horizon "becomes full before the biennial review." Id., pp. 6-9.

While concurring with some of the criticisms offered by intervenors concerning Consumers' initial proposals, the Staff recognized and expressed appreciation for several compromises subsequently made by the utility. See, Staff's reply brief, pp. 6-8. With regard to the company's revised standard offer tariff, the Staff stated that it:

> Appreciates the Company's proposed compromises to increase the QF size cap from 100 kW to 1.5 MW [and] lengthen the contact term options

[5] In this regard, the Staff recommends that, for utilities like Consumers needing capacity during PURPA's 10-year capacity planning horizon, the future standard offer cap should be 1 MW when 0 to 100 MW of capacity are needed during the succeeding 2 years, 2 MW when up to 200 MW is needed, 3 MW when up to 300 MW is needed, 4 MW when up to 400 MW is needed, and 5 MW whenever more than 400 MW is needed. Id., citing 2 Tr. 138-139, and Staff's reply brief, p. 7.

> to 10 years provided the . . . forecasted energy rate is refreshed after 5 years. Additionally, the Company compromised on the capacity payment criteria and agreed to pay a QF for avoided capacity if the Company has a need for capacity in the first 5 years of the 10-year PURPA planning horizon. If the Company does not need capacity in the first 5 years, then the Company proposes that the avoided capacity payment be based on the PRA. At the time of the energy price update, if the Company needs capacity during the first 5 years, then contracts based on the PRA would be updated to the capacity payment based on the NGCC.

Id., p. 6.

With regard to the criticisms offered by intervenors in this case, the Staff specifically (and, as noted earlier) agrees with the ELPC that it would be inappropriate for Consumers to value capacity at the PRA "if the utility needs no capacity in years 1 through 5 of the 10-year PURPA planning horizon, but needs capacity in years 6 through 10." Id., p. 8. In this regard, the Staff notes that:

> Utilities look beyond 5 years when deciding whether to build a large plant and build for future need, and may choose to build in excess of actual need, such that they may not have need for 5 years. Rather than filling the remaining five years with QF purchases to avoid having to go to the expense of building new, it could then buy from the PRA and avoid QF purchases entirely, as testified by [ELPC witness, Douglas B. Jester].

Id., citing 2 Tr. 248. According to the Staff, and as correctly noted by the ELPC, this would "defeat the purpose" of PURPA's passage. Id., citing the ELPC's initial brief, pp. 10-12. As such, the Staff continues to support setting the avoided capacity cost to be adopted for Consumers through use of the proxy price provided by an NGCT facility "when capacity is needed at *any* time in the 10-year PURPA planning horizon." Id., emphasis in original.

The Staff goes on to note that, after this case was initiated, Public Act 341 of 2016 (Act 341) was passed by the Legislature, signed by the Governor, and is set to take effect on April 20, 2017. Among other things, Act 341 requires the Commission to conduct a hearing every five years for utilities like Consumers to reevaluate the procedures (including the establishment of avoided cost rates) as were originally established in Case No. U-6798. See, MCL 460.6v(1). As pointed out by the Staff, following the conclusion of that hearing, Act 341 requires that the Commission issue an order that does all of the following:

> (a) Ensure that the rates for purchases by an electric utility from, and rates for sales to, a qualifying facility shall, over the term of a contract, be just and reasonable and in the public interest, as defined by PURPA.
>
> (b) Ensure that an electric utility does not discriminate against a qualifying facility with respect to the conditions or price for [the] provision of maintenance power, backup power, interruptible power, and supplementary power, or for any other service.
>
> (c) Require that any prices charged by an electric utility for [providing] maintenance power, backup power, interruptible power, and supplementary power, or for any other services, are cost-based and just and reasonable.
>
> (d) Establish a schedule of avoided cost price updates for each such utility.
>
> (e) Require electric utilities to publish on their websites template contracts for power purchase agreements for qualifying facilities of less than 3 megawatts that need not include terms for either price or duration of the contract. The terms of a template contract published under this subsection are not binding on either an electric utility or a qualifying facility and may be negotiated and altered upon agreement between an electric utility and a qualifying facility.

Staff's reply brief, p. 9, citing MCL 460.6v(4).

The Staff contends that the present proceeding should qualify as the first 5-year review for Consumers pursuant to Act 341. Nevertheless, it asserts that there is a general area that "would be better addressed in a different proceeding." Id. Specifically, because cost-based rates for such things as maintenance power, backup power, interruptible power, and supplementary power were not addressed in this case, but are currently being dealt with by the Standby Rate Working Group that the Commission previously initiated in Case No. U-17735, the Staff feels that those issues should be dealt with in that case. See, Id., p. 10. In the alternative, the Staff states that (assuming Consumers' files a general rate case within the next five years)[6] those cost issues could easily be addressed in that proceeding as well. See, Id.

Therefore, the Staff contends that Consumers "failed to show that the public interest would be served" by reducing the length of any potential QF contracts to a level "that would almost certainly prevent future QF development" within its service territory, as well as threatening "to make the functioning of current QFs impossible." Staff's initial brief, p. 16. In contrast, the Staff asserts that it, as well as several of the other parties in this docket, provided "substantial evidence showing that maintaining the choice of at least a five, ten, or fifteen year term" by QFs for PURPA-based agreements is in the public interest. Id.

"In addition to the factual record," the Staff continues, "the Commission must also consider PURPA's legal requirements" as discussed earlier in this PFD and as set forth in both the Act and the attendant rules promulgated by the FERC. Id. In this regard, the Staff asserts that the terms offered by Consumers' must "balance the interests of the public, the QFs, and the Company," including offering a sufficiently-long contract length and the option to use forecasted capacity and energy costs, as outlined in the Staff's briefs. Id. This would include the Commission's consideration of using "transfer price schedule inputs," as well as "the inputs suggested in Consumers' application in terms of

[6] Which, based on recent history for the utility, is a fairly reasonable assumption.

Staff's proposed option No. 3" (i.e., use of avoided costs based on an NGCT as the proxy plant). Id.; See also, Staff's reply brief, p.10.

C. IPPC

As noted earlier, the IPPC offered five witnesses in this case. And, consistent with their evidence, it asserts that "both the Company's and the Staff's avoided cost methodologies must be rejected" because neither of them reflects the "full avoided costs," and therefore "are not just and reasonable" for Consumers' customers. IPPC's initial brief, p. 49. Specifically, the IPPC argues that those methodologies "do not properly account for the value of the reliable, baseload generation" provided by its members, and also:

> [f]ail to encourage their development, are discriminatory in application compared to how the Company is compensated under the Transfer Price Schedule for long term (mostly 20+ year) contracts for its own renewable energy projects and those [implemented] pursuant to [2008 PA 295 (Act 295)], are not in the public interest, as they discourage the continued operation of IPPC's members' QFs, and otherwise violate PURPA, as well as FERC's rules and regulations implementing that law. The only avoided cost methodology that the Commission [ordered to be reviewed] in this docket which satisfies the requirements of PURPA and could be applied to the IPPC members' QFs without discriminatory impact is the Transfer Price Schedule. Therefore, IPPC urges this Commission to adopt the Transfer Price Schedule as the avoided cost methodology that will apply to IPPC's QFs in Michigan.

Id., See also, IPPC's reply brief, pp. 14-24.[7]

[7] According to the IPPC, the transfer price schedule developed pursuant to Act 295 is intended to be representative of what "a Michigan electric provider would pay had it obtained the energy and capacity (the non-renewable market price component) through a new long term power purchase agreement," and which is essentially based on fossil-fuel based generating facilities. Id., p. 14 [citations omitted]. The IPPC thus contends that the transfer price, which the Commission has approved for use in the past, and which Consumers itself has relied upon for application to its renewable generating units, is the only methodology discussed in this proceeding that establishes capacity and energy prices to be paid to QFs that are both sufficient and non-discriminatory. See, Id., pp. 14-22.

In support of its over-arching assertion stated above, the IPPC asserts that an avoided cost methodology (like that initially proposed by Consumers) which relies upon MISO's short-term residual market--including the application of ZRC credits--to establish energy or capacity values is not only unjust and unreasonable, but is also discriminatory to IPPC's QFs and violates PURPA. See, IPPC's initial brief, pp. 14-19; See also, IPPC's reply brief, pp. 6-9. It goes on to contend that, even under the utility's decision to now seek approval of "a modified version of the Staff's proposed avoided cost methodology" [under which QFs would be subject to the utility's 5- and10-year planning horizons, and have their capacity payments set at (1) the levelized NGCC proxy plant's capacity cost if need was shown during the first 5 years, or (2) at the cost level set by MISO at its annual PRA auction, if no such short-term need was anticipated], would still constitute a violation of PURPA. See, IPPC's reply brief, pp. 4-5.

The IPPC asserts that "it is also plain" that the company "is attempting to subject payments to QFs to the same 'reasonable and prudent' analysis of costs" that are imposed upon regulated utilities. Id., p. 5. According to the IPPC, such an approach would appear to be at odds with the FERC's directions concerning the implementation of PURPA which, it claims, noted that:

> While State commissions are accustomed to evaluating costs and rates on the basis of what is reasonable under a cost of service framework, nevertheless '[a] major portion of this legislation is intended to exempt [QFs] from the cost-of-service regulation' under which electric utilities traditionally have been regulated.

Id., citing FERC order 69, at p. 12,222. This argument, the IPPC contends, applies equally to avoided capacity and energy payments made to QFs that operate within Consumers' service territory (including MISO's ZRC requirements). See, Id., pp. 6-9.

Moreover, the IPPC objects to allowing the utility to capture any part of the RECs that arise from the operation of a QF, arguing that if the company wants to "retain the environmental attributes" arising from the environmentally-benign electric generation that is ultimately provided to its customers, "it can do so through negotiation with the QF within the [PURPA] contract" and set a price for those [RECs] outside of the avoided cost rate. Id., p. 12.

The IPPC goes on to support the Staff's opposition to Consumers' proposal to limit the length of standard offer contracts to only five years, agreeing that limiting the term of those agreements to such a short length of time "would run afoul of [the] FERC's standard contract provisions" because imposing such a limited duration on QF contracts "would not compensate GFs for their capacity contributions" to the utility's system. IPPC's reply brief, p. 20, citing Staff's initial brief, pp. 10-11. As the Staff correctly noted, the IPPC continues, the receipt of electrical power from a QF "can only cause Consumers to defer or cancel [the construction of] future capacity projects, as PURPA envisions," if the QF is allowed to "enter into contracts to provide capacity for a sufficiently long term." Id., citing Staff's initial brief, p. 13.

Nevertheless, the IPPC potentially diverges from the Staff's position regarding the length of the utility's contracts with smaller QFs that do not make use of the standard offer contract, specifically questioning whether or not:

> The Staff's position encompasses any utility purchases for QF energy and capacity with QFs that are 20 MW and below [as discussed in 18 CFR 292.304(d)], or only for Standard Offer contracts, according to 18 CFR 292.304(c). The IPPC asserts that [the] FERC interprets section 304(d) – which allows long-term contracting at forecasted rates at the option of the QF – to be allowed for all QFs 20 MW or under, not simply those who may be able to utilize a state-approved Standard Offer contract pursuant to 292.304(c).

> Therefore, while the IPPC appreciates and continues to support [the] Staff's proposal of 5, 10, and 15-year contract terms under the Standard Offer, the option for a QF to enter into a long-term contract should clearly be allowed for any QF 20 MW and under, and the term should extend up to a 20-year option. The 20-year period recognized under the Transfer Price for utility facilities continues to be relevant, especially with the passage of Public Acts 341 and 342, under which the Transfer Price will continue to be used by the utilities, based on their renewable energy plans – including their "capital, operating and maintenance costs" over a 20-year period. MCL 460.1047(2)(i).
>
> As [the] Staff notes, QFs need contractual terms long enough to ensure financial stability and the ability to obtain financing. Staff's Intial Brief, p. 13. Ten or 15-year contracts should not necessarily be the outer boundary, as the Legislature has determined that 17.5 years is a reasonable minimum contractual length to support a QF's financing period. See, MCL 460.6j(13)(b)(ii). This provision was not changed in the recent statutory amendments under Public Act 341 of 2016.

IPPC's reply brief, pp. 20-21. The IPPC thus asks that the Commission allow any PURPA contract--whether based on the standard offer or a separately-negotiated agreement--to include the option of selecting a term of up to at least 20 years. See, Id., p. 22. This would, the IPPC contends, allow QFs to enter into contracts that would be "similar to the duration of the Company's own renewable energy projects" provided under the transfer price schedule. Id.

Turning to the issue of how to treat the renewal of existing QF contracts, the IPPC agrees with the Staff that a continually-operating QF should "receive the full capacity payment" whether or not Consumers claims to have a need for capacity during the 10-year PURPA planning horizon. Id. According to the IPPC, this assertion is based on the fact that existing QF-provided generation is (or, at a minimum, should already be) part of the utility's long-term capacity planning, and that the company should not be able to simply move to supplant existing QFs in the future with new, utility-owned generating plants. See, Id. Doing otherwise, it claims, "would fail to encourage small power production," and instead "open the door to utility manipulation of the capacity market" in a way that would serve to "squeeze out QF resources [whenevere] their contracts terminate." Id.

Finally, and consistent with its assertions set forth above, the IPPC concurs with the Staff's belief that (1) MISO's PRA is "a wholly inadequate basis for determining capacity pricing," and (2) "both a standard line loss credit, and an additional credit covering those QFs" that are connected to Consumers' system "at a lower voltage level or can otherwise show a reasonable likelihood of line loss savings" should be applied. IPPC's reply brief, p. 23, citing Staff's initial brief, p. 8. In this regard, the IPPC continues, "the Commission should make clear" that each of those line loss-related credits "should be available not only under the Standard Offer but also, where applicable, for all QFs 20 MW and under." Id.

D. ELPC

For its part, the ELPC asserts that the Staff's general recommendation to use the cost of a NGCT proxy plant when establishing Consumers' avoided capacity costs, as well as the cost of a NGCC (plus the ICE adder) to set the utility's avoided energy costs, should be adopted by the Commission. See, ELPC's initial brief, p. 3, as well as ELPC's reply brief, pp. 2-4. However, it continues, a process should also be initiated for the quantification (and addition to those avoided costs) of the various savings produced by the purchases from QFs, such as the reduction in transmission costs and line losses, avoided emissions and their related environmental compliance expenses, and the hedging value that would be accentuated by accepting capacity and energy from QFs.[8] See, ELPC's initial brief, p. 3.

The ELPC went on to assert that, as correctly noted by the Staff, and confirmed by the testimony offered by a host of other parties,[9] any attempt to limit the term of a QF's contract to something as short as 5 years would be anathema to PURPA's intent of promoting QF growth and investment. See, ELPC's reply brief, p. 5. Rather, the ELPC contends that the only way to use the capacity and energy from QFs to cause a utility, such as Consumers, "to defer or cancel future capacity projects [is] if the QF is able to enter into contracts to provide capacity for a sufficiently long term," such as agreements of at least 15 years in length. Id., citing Staff's initial brief, p. 13. In support of this contention, the ELPC points out that, to be consistent with PURPA's intent, "a legally enforceable obligation should be long enough to allow QFs reasonable opportunities to attract capital" from any potential investors. Id. As testified to by Adam Schumaker, the Director of Business Development for the Sustainable Power Group, LLC, "15 years is the shortest [Power Purchase Agreement] term required to make solar projects financeable," and a 20-year contract would be both preferable for the QFs and more beneficial to ratepayers. Id., citing 2 Tr. 276-277. For many of the same reasons, the

[8] According to the ELPC, the Commission should immediately commence a proceeding in order to quantify these various cost savings in order for them to be included "in the next biennial review of PURPA avoided costs." ELPC's reply brief, p. 4. That proceeding, it suggests, "should involve all the utilities and other parties of interest in order to consider the available data and potential methodologies" needed to accurately calculate and quantify these costs/cost savings "with the goal of recommending to the Commission the methodology that should be applied going forward." Id., pp. 4-5.

[9] These witnesses include Geoffrey C. Crandall (from GLREA); Kenneth Rose, Ph.D., Thomas V. Vine, and Nelson P. Turcotte (from the IPPC); and Douglas B. Jester and Rand Dueweke (from the ELPC). See, 2 Tr. 48, 55, 81, 104-105, 117, 256, and 288.

ELPC objects to Consumers' proposal to update the forecasted energy price that it would pay to QFs every five years.[10] See, Id., pp. 5-6.

Turning to the standard offer tariff, the ELPC argues that the Commission should adopt the Staff's proposed tariff language regarding the methodology to be used to calculate the utility's avoided capacity and energy payments, as set forth in Exhibit S-1. See, ELPC's initial brief, p. 4. Nevertheless, it continues, the Staff's proposed tariff should be amended to "extend the standard offer rates to projects up to 20 MW in size, and to set contract terms of no less than 15 years." Id. In addition (and as noted briefly above), the ELPC agrees with several of the other parties that the Commission should "order a study to quantify other avoided costs, such as line losses and other quantifiable costs" that are avoided by Consumers' purchase of capacity and energy from QFs, and then reflect those savings "in the tariff approved by the Commission in the next biennial review of avoided cost." Id.

Finally, the ELPC addressed the potential effects on PURPA-based QF contacts arising from the recent enactment of revisions to Michigan's laws regarding the production and distribution of energy. Specifically, it noted that, as of April 20, 2017, Consumers will be required to comply with Michigan's updated renewable portfolio standards (RPS),[11] as well as its Customer-Requested Renewable Energy (CRRE)

[10] In this regard, the ELPC contends that, among other things, allowing for 5-year updates to forecasted energy costs "ignores PURPA's implementing regulation that explicitly condones differences between forecasted and actual rates." See, Id., p. 6, citing 18 CFR Section 292.304(b)(5).

[11] The revised RPS raises the amount of renewable energy that Consumers must use in meeting its customers' electric needs from its current level of 10% to a minimum of 15% by 2021, with an interim requirement of 12.5% by 2019, as well as a goal of 35% by 2025.

requirement.[12] See, ELPC's reply brief, p. 7, citing MCL 460.1027(3), 460.1028(1), and 460.1061. With regard to these changes, the ELPC asserts--as do others in this case--that the RECs created by QFs that contract with Consumers (both under PURPA, and in accordance with the new RPS and CRRE) should not be transferred to the utility, as the company and the Staff argue. See, Id., pp. 7-9. In support of this assertion, the ELPC points out that:

> As [the] FERC has explained, "a state regulatory authority may not assign ownership of RECs to utilities based on a logic that the avoided cost rates in PURPA contracts already compensate QFs for RECs in addition to compensating QFs for energy and capacity, because the avoided cost rates are, in fact, compensation just for energy and capacity."

ELPC's reply brief, p. 8, citing Windham Solar LLC and Allco Finance Ltd., 156 FERC P61,042, para. 4 (2016). Moreover, it points out that RECs have a value (which is actually issued, tracked, and traded on the Michigan Renewable Energy Certification System) separate from the MW per hour of energy expended to create the REC itself. See, Id. Therefore, the ELPC asserts that the Commission should either (1) reject in full Consumers' request that the RECs be assigned to the utility, or (2) ensure that the avoided cost relating to any REC is fully recognized in the company's avoided cost methodology. See, Id., p. 9.

For the reasons stated above, the ELPC contends that the Commission should: (1) adopt the Staff's proposed tariff language, as set forth in Exhibit S-1, with regard to the methodology for calculating the avoided capacity and avoided energy payments to be made by Consumers to QFs operating within its service territory; (2) amend that

[12] Under the CRRE requirement, customer demand for additional, technology-specific renewable energy capacity will likely drive the amount of that energy that Consumers must ultimately include in its portfolio, and thus should also be considered when setting its avoided costs.

proposed tariff to extend the standard offer's rates to projects up to 20 MW in size, and to also set the terms for any such agreement at a minimum of 15 years; (3) order that a study be conducted to quantify other quantifiable avoided costs--such as line loss reduction, etc.--that may then be included in the tariff approved by the Commission in the next biennial review of the utility's avoided costs, and (4) require that, whenever the company's purchases from QFs "comply with renewable energy requirements or meet customer demand for renewable generation," as through the application of the CRRE requirement, Consumers' avoided cost "should be set no lower than the Company's cost of meeting those specific requirements. Id., p. 10.

E. GLREA

GLREA begins by noting that it agrees with several of the parties' positions stating that the objectives of PURPA are to both "promote and make possible the expansion of independent renewable energy and small power projects." GLREA's reply brief, p. 1.[13] Moreover, it contends that another "purpose and objective of PURPA" is to encourage fair competition in the energy generation field, "without providing deference or 'preference' to a utility's monopoly power and dominance." Id.

GLREA also expresses agreement with the Staff and other parties that: (1) the avoided capacity and energy cost determinations must be "just and reasonable, non-discriminatory, and in furtherance of the public interest;" (2) those avoided costs should be "set at a level that places the utility and the [QFs] on a level basis commensurate with the cost the utility would otherwise incur" for added capacity and

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[13] In this regard, GLREA cites to the initial briefs filed by the IPPC, the ELPC, and the Staff. See, GLREA's initial brief, p. 1, fn. 1.

energy, “including costs involving line losses, transmission, environmental and other impacts, or other cost factors;” and (3) the PURPA contracts entered into by Consumers must be of a long enough duration to “avoid discrimination as between PURPA and utility projects, and to provide needed certainty to make PURPA projects financeable” in the future. Id., p. 2. With regard to this last point, GLREA argues:

> [G]iven that [Consumers] as a utility plans additional capacity and energy arrangements over a long term planning horizon, with the added benefit of obtaining ratemaking treatment of its plant investments, purchased power transactions, or other capacity and energy transactions, pursuant to [Commission] regulation in general rate cases and under 1982 PA 304 (Act 304), [the utility] plans capacity additions, often in large increments, with planning horizons for at least 25 years or more, and receives rate recognition of said projects (often with little risk) in the rate making formula which includes rate of return on investment, depreciation of investment, recognition of operation and maintenance expenses, taxes, working capital, among other benefits. In contrast, independent PURPA projects [i.e., QFs] assume the risk of raising their own capital to build projects, to finance needed administration, legal, or accounting costs, and to cover their own operation and maintenance expenses, taxes, among other costs. In order to put utility and PURPA projects on a level playing field, and on a non-discriminatory basis, the inescapable conclusion must be that the PURPA project contracts must be of reasonable long-term duration, comparable to the commitments given to the utility with respect to [its] incremental project plans and undertakings.

Id., p. 3.

It is also asserted by the GLREA that, in support of requiring utilities to enter into PURPA agreements that extend beyond the limited duration first proposed by Consumers in this case, it must be recognized that Act 304 (which provides for the entry into QF contracts of up to 17.5 years or longer) was essentially reaffirmed by Michigan’s new energy legislation [i.e., PA 341 and PA 342], which also supports having the state take steps to “further expand renewable energy projects, energy efficiency, [and the] reduction of energy waste.” Id., at p. 4.

GLREA further contends that the overall avoided cost level adopted by the Commission should, in keeping with Michigan's recent enactment of Acts 341 and 342, be based on "a method that transitions avoided costs from current market prices" to the Cost of New Entry [CONE]," and one which is based on a "comparative integrated resource planning [IRP] analysis." GLREA's initial brief, p. 5.

Finally, GLREA agrees with the parties supporting the extension of the standard offer contract to any and all PURPA projects rated at 20 MW or less. See, Id. According to it, "the reality is that the evidence and suggested basis for [restricting] the tariff to smaller projects is severely lacking," and that extending that agreement to all prospective QFs producing 20 MW or less of electricity would be in the public interest. Id. As a result, GLREA asserts that the Commission adopt the positions set forth by its witness, Mr. Crandall, as well as those set forth above that it expressed agreement with.

F. Cadillac

By way of its briefs, Cadillac makes three particular points. First, it notes that both the Staff and the utility expressed agreement that existing QFs within the utility's service territory should (and would) be compensated under the terms of their current contracts until the expiration of those agreements. See, Cadillac's initial brief, p. 1; See also, 2 Tr. 157 and Exhibit MLP-1. Second, Cadillac asserts that, following the expiration of an existing contract, the QFs should be compensated at the rate arising from the Staff's avoided cost methodology if they elect to provide capacity and energy under the standard offer tariff, or under a different negotiated rate, if that is what any QF and the company find to be more to their liking. See, Id. Third, Cadillac argues that the avoided cost rates approved in this case "should apply only to new contracts with QFs having a capacity of 20 MW or less, and should not apply to any existing PPAs." Id., p. 2.

G. MPLP

Much like Cadillac, MPLP asserts that testimony provided in this proceeding by both Consumers and the Staff, and which was not contradicted by any of the other parties' witnesses, shows that the avoided cost rates approved in this case "should impact only future PPAs, not existing PPAs." MPLP's initial brief, p. 3. With regard to this assertion, MPLP notes that federal law "prohibits altering avoided cost rates in existing PPAs with QFs."[14] Moreover, it points out that because both the MPLP and Ada facilities can produce electricity in excess of 20 MW (being rated at 123 and 30 MW, respectively), their current operations should not be effected by the outcome of this case. See, Id. It therefore recommends that the ALJ issue a PFD concurring with those assertions.

III.

DISCUSSION

Notwithstanding the number of witnesses and exhibits presented in this case, the potential dollars at stake, and the tariff language about which the various parties are highly concerned, this proceeding is actually not terribly difficult to resolve.

The primary question faced by the Commission is what level of avoided cost, including both capacity and energy components, should be adopted for future use in

[14] Concerning this claim, MPLP cites Freehold Cogeneration Associates LP v. Board of Regulatory Commissioners of New Jersey, 44 Fed 3d, 1178, 1194 (1995), which asserts that once a state commission approves a PPA on what it then found to be the utility's avoided cost, any action designed to reconsider the approval of that avoided cost rate is preempted by federal law. Id.

Consumers' service territory with regard to PURPA-based contracts (both existing and potential), as well as what standard offer tariff language should be used to best address the various issues raised by PURPA's implementation in Michigan with regard to smaller QFs. In this regard, six issues need to be addressed based upon the evidence and arguments described above. Each of these issues will be dealt with seriatim.

A. Consumers' Avoided Capacity Costs

Much to its credit, Consumers backed away from the four-tier capacity cost proposal that it initially offered in this case. Instead, it now recommends adoption of a structure that would employ an avoided capacity cost based on the levelized fixed cost arising from a NGCC plant, which would be updated (at least potentially) whenever the utility shows a need for added capacity in years 1 through 5. In contrast, the IPPC proposes simply applying the transfer price that has already been built into the capacity costs paid to company-owned PURPA facilities.

The Staff, on the other hand has provided an option that, based on both the evidence and arguments presented in this case,[15] appears to be more in line with the intent of PURPA and the State of Michigan's application of that statute to utilities within the state. Specifically, the Staff's recommendation, which would set avoided capacity costs at a level that would be equal to a NGCT's capacity costs, is both logical and best supported on the record.

[15] As discussed previously, the ELPC supports the Staff's proposal to use a NGCT proxy plant for the computation of the avoided capacity cost adopted in this case. GLREA agrees, albeit grudgingly, with the Staff and others that use of the NGCT plant costs is the best way to proceed, however it also asserts that the resulting price must be just and reasonable, non-discriminatory (i.e., not in favor of the utility), and in the public interest. Moreover, as noted by Mr. Devereaux, use of the CONE and IRP-based methodology initially proposed by GLREA would both "may not represent the company's avoided costs" and is not required by statute. Consumers' reply brief, p. 52, citing 2 Tr. 343.

As specifically noted by Mr. Harlow, a NGCT facility is "relatively quick to build," tends to be "less costly" in terms of overall construction, and is designed such that Consumers can cycle it "on and off" as needed, therefore reducing its overall cost of operation. See, supra, citing 2 Tr. 160. Thus, in essence, a plant like this would essentially be a peaking unit, only used during times of peak electrical need (i.e., warm days during which an unusually large amount of air conditioners were being operated in unison), and not being used as a baseload facility would be, namely on a 24/7 basis regarding energy production and without a focus on Consumers' temporal energy requirements. See, 2 Tr. 160. Such a plant, particularly with its potential to accentuate the possibility of distributed generation, and thus the reduction of line losses and possible outage issues throughout Consumers' service territory, seems to make the most sense as a basis for both the construction of additional generating units and for the calculation of avoided capacity cost.

Still, based on Mr. Harlow's testimony, the record further supports approving the Staff's proposal to take into consideration the effects of ZRCs used by MISO to evaluate Consumers' actual capacity needs in the future, albeit only with regard to intermittent generation resources such as wind- and solar-powered energy. See, 2 Tr. 160-161. Moreover, the ALJ agrees with the Staff that (1) any electric capacity Consumers may need over its current 10-year planning horizon should come from either existing or new/willing QF suppliers, if possible, (2) all of the QFs currently supplying capacity to the utility should have their expiring contracts renewed at the full standard offer rate--as opposed to the PRA--regardless of whether the company expresses that it has additional capacity needs based on its then-current 10-year planning horizon, and (3) with regard to any new QFs, capacity payments would be set at the PRA if, indeed, Consumers' capacity need over the 10-year capacity planning period has been fully satisfied. See, Id.

In addition, the ALJ agrees with Cadillac and the MPLP (as well as others) that the rates established in this proceeding should not apply to existing QF agreements, but rather only to new QF contracts (regardless of whether they rely on the standard offer tariff or some other negotiated agreement). Moreover, the ALJ also notes that--as will be discussed later--although the standard offer tariff should be extended as an option for use by any QF producing 20 MW of power or less, this would not apply to the MPLP because its facilities both produce and deliver power to Consumers in excess of that level.

B. Consumers' Avoided Energy Costs

As with its capacity charge proposal, and as noted above, Consumers moved away from its initially-proposed four-tier structure regarding avoided energy costs. Instead, it now advocates the adoption of a structure under which the avoided energy costs awarded to QFs would be based upon either (1) the lesser of the utility's forecasted LMP or the forecasted variable energy cost of a NGCC, or, in the alternative, (2) the lesser of the company's actual LMP or the actual variable cost for an NGCC (which, it suggests, should be available for use by both those QFs who prefer to make use of the standard offer, as well as those that want to negotiate separate PPAs). Consumers' initial brief, p. 11, citing 2 Tr. 318. As noted above, the IPPC continues to assert that the only logical and fair cost rate assigned to energy provided to Consumers' system would be the utility's existing transfer price. See, IPPC's reply brief, pp. 14-16. In contrast, the

Staff continues to support its three-option proposal, as explained earlier. See, Staff's initial brief, pp. 5-6; See also, 2 Tr. 157-162.

The ALJ again finds that the proposal offered by the Staff (and specifically supported by GLREA and the ELPC), makes the most sense regarding the pricing of avoided energy costs. As noted above, the structure proposed by the Staff would give QFs the choice of: (1) adopting energy prices based on the actual LMP, (2) using the then-existing forecasted LMP price over the term of the contract, or (3) accepting a proxy price based on the forecasted variable energy cost of a NGCC plant, along with an ICE adder.[16] This seems to be a reasonable accommodation for the interests of Consumers, the QFs, and ratepayers, each.[17] Finally, the ALJ agrees with Cadillac that, as with capacity payments made to its QFs, the utility should continue to pay the existing energy charge rates for the duration of each QFs' current contracts, and only apply the Staff's three-option methodology to new QFs offering 20 MW or less in the way of electrical capacity and energy.

[16] In this regard, however, the ELPC continues to caution against Consumers' plan to update the energy price every five years. The ALJ fails to see the logic in the ELPC's proposal. Because existing QFs' energy prices would be locked-in for the duration of their respective agreements, they would be held harmless from any changes to the initial energy price that they selected. When the time comes for negotiating a new price (or adopting the energy price set forth in Consumers' standard offer contract), they can then make the decision as to whether they seek to serve as a QF on Consumers' system or simply offer their capacity and energy to MISO. As a result, the ALJ finds that the ELPC's assertions on this point should be rejected by the Commission.

[17] Alternatively, the ALJ agrees with both Consumers and the Staff that adopting the IPPC's request to apply the existing transfer price to QF-supplied power would leave the utility, and thus its ratepayers, likely paying an excessive price for this electricity. See, Consumers' reply brief, p. 12; See also, Staff's reply brief, pp. 1-5. Moreover, as noted by the Staff, the model it proposed--and which is recommended for adoption in this case--is "identical to that used to calculate the transfer price," albeit with the use of different (and, presumably, updated) inputs regarding plant size, plant capacity factor, heat rate, fuel costs, fixed charge rates, operation and maintenance costs, and capital costs that result in a substantially lower avoided energy cost to be borne by Consumers' customers. Id., citing 2 Tr. 162, as well as Exhibit S-6.

C. Standard Offer Tariff Language

As noted earlier, Consumers initially proposed a 4-tier avoided cost structure under its standard offer tariff, with a 5-year term, as well as a limitation that it only be applied to QFs providing 100 kW or less in the way of capacity and energy. However, the utility revised its proposal significantly during the course of these proceedings. Now, what the company suggests for adoption is that the size of any QF offering made pursuant to the standard offer tariff be capped at 1.5 MW, and that the contractual term applied to the QF either be set (1) at 10 years if "actual energy pricing" is selected, or alternatively (2) at 5 years if the QF opts instead for "forecasted energy pricing." See, Consumers' reply brief, pp. 15-18.

In contrast, the Staff--as expressed in Exhibit S-1 and noted above--appears to suggest a total of nine alterations to the language included in Consumers' standard offer tariff. Based on both the evidence provided in this case and the intent of PURPA, the FERC rulings regarding that statute's implementation, Michigan's related legislation, and past Commission orders, the ALJ finds that seven of the Staff's suggestions should be adopted in this proceeding. These are to: (1) begin immediately with a 2 MW cap on the standard offer tariff, which can be later set anywhere from 1 to 5 MW, depending on the potential level of capacity shown to be needed in Consumers' 10-year planning horizon, (2) provide QFs with line loss credits where applicable, while not limiting them to the initial 2.37% figure proposed by the utility, pending the receipt of additional support for that figure--as well as information regarding transmission savings, environmental compliance costs, etc.--in the context of the company's next biennial avoided cost review, (3) allow QFs that elect to provide capacity and energy by way of the standard offer tariff to choose which of the three energy payment proposals suggested by the Staff should be applied to their particular PPAs, (4) let those QFs participate in the two-prong capacity payment plan proposed by the Staff, under which QFs that are renewing their status receive the full standard offer tariff rate, and allowing QFs that are new to the system to be assigned the PRA-based rate if the utility is not viewed as being short of capacity during its then-applicable 10-year planning horizon, (5) reexamine the standard offer tariff as part of the company's biennial review process, (6) allow for *ex parte* review of all standard offer tariff-based contracts when submitted, and (7) give Consumers the opportunity to file a case to reduce the price used for standard offer agreements to the PRA level if its 10-year planning horizon calls for no new capacity.

There are, however, two areas where the ALJ disagrees (at least in part) with the standard offer tariff proposal suggested by the Staff. The first is that, while it seems both reasonable and feasible to allow QFs supplying both capacity and energy to elect whether to choose a 5, 10, or 15 year term, as the Staff suggests, the potential cap on a QF's contract term should, the ALJ concludes, be pushed to up to 20 years, as proposed by the IPPC, the ELPC, and GLREA. The 20-year term for contracts of this type not only corresponds with the planning length generally employed by Consumers for its own generating units, but also is consistent with the terms discussed in Federal Acts 341 and 342. In addition, it comes close to the 17-½ year term contained in Michigan's statues, such as Act 304, and thus would--by extending the likely pay-back period--allow for the easier financing and construction of QF facilities. The ALJ therefore recommends that a 20-year term option should be extended to QFs, while also suggesting that his proposed resolution of this issue be specifically addressed in the context of Consumers' next biennial review.

Second, and as noted previously, numerous parties have asserted that RECs arising from the production of capacity and energy from QFs, both under PURPA and in accordance with the newly-created RPS and CREE here in Michigan, should not be automatically transferred to the utility. Rather, and as explained by the FERC (by way of its ruling in the Windham Solar case, cited earlier) RECs should flow to the QFs instead of the company. The only way to do this, as noted by the ELPC, is to rule that none of the RECs created by the operation of a QF ever be assigned to Consumers, on the one hand, or that the "avoided cost relating to any REC is fully recognized" as part of the particular utility's avoided cost methodology, on the other hand. See, ELPC's reply brief, p. 9. The ALJ finds the ELPC's proposal to be the most reasonable of those offered with regard to this issue, and thus recommends that the Commission either rule that RECs should stay with the QFs that create them, or, alternatively, be fully recognized as a portion of the avoided cost figure applied to the QF in question during the course of contract negotiations, if such occur.[18]

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[18] In reaching this conclusion, the ALJ notes that the electric production facility owner -- whether Consumers or the QF -- may have been able to use a more environmentally benign, albeit also a possibly more expensive, fuel source and structure for their respective facilities. By choosing the type of plant that might likely produce less profit, but also less in the way of environmental contaminants, their actions would be more in line with the structure and intent of Michigan's implementation of both the RPS and the CREE, as well as the federal government's implementation of PURPA itself. As a result, it only seems logical that the Commission require RECs to either be assigned directly to the QFs whose actions gave rise to them, or to at least be factored into the computation of the utility's avoided cost payments to those QFs. The ALJ thus recommends that that, for simplicity's sake, all RECs developed under a standard offer contract be assigned to the QF, whereas any such RECs produced by a QF that elects to provide capacity and electricity under a negotiated agreement with Consumers should be subject to negotiation between the QF and the utility.

In addition to those issues, and although it was not addressed by the Staff and several of the other parties to the degree of the above-mentioned matters, the ALJ also finds that careful consideration should be given--possibly in the course of Consumers' next biennial review process--to also increasing the cap on the standard offer contract to 20 MW, as apparently allowed by the FERC. See, IPPC's reply brief, pp. 20-21. Because no significant justification was provided in this case for not eventually increasing that cap to 20 MW, the ALJ recommends that the parties specifically be directed to address this matter in the utility's next biennial review.

D. Forecasting Horizon

Initially, Consumers and the Staff had a dispute regarding the forecasting horizon that should be applied to the utility. However, in this course of this proceeding, the company elected to agree with the Staff that capacity needs within its service territory should be considered over the company's 10-year planning horizon, albeit with 5 years as the target for making "definite capacity decisions." Consumers' reply brief, p. 11. Doing so would effectively allow the potential capacity payment from the utility to be set, and also known by any existing or prospective QFs, five years out.

None of the parties have expressed significant objection to this proposed structure, and it strikes the ALJ as a reasonable method of proceeding in the future. Thus, it is recommended that the Commission approve this means of setting Consumers' likely capacity need level in the future.

E. Other/Miscellaneous Avoided Costs

The next area that must be addressed by the Commission concerns the treatment of other avoided expenses, as well as financial benefits, that Consumers (as well as other parties) contend arise from the use of QF-generated power. As noted previously, the utility recognizes that reduced transmission costs, line loss mitigation, reduced carbon emissions and their corresponding environmental compliance costs, and the hedging value accrued due to the use of QFs, should all, logically, be recognized when computing avoided costs. However, Consumers asserts that each of those costs and benefits (1) should only be included in the computation of avoided costs to the extent that they can be directly quantified/calculated, as opposed to being theoretical in nature; (2) should be valued and applied in a reciprocal manner, by which QFs would be required to reimburse the utility and its ratepayers in situations where a QF's provision of power actually increases the rate of line losses, etc.; (3) as requested by the utility--and discussed earlier in this PFD--all RECs arising from the operation of the QFs that elect to provide service pursuant to the standard offer tariff should flow to Consumers, as opposed to any of those particular QFs [while still being an issue that would be open for negotiation for other QFs that seek a negotiated PPA]; and (4) again, as also discussed earlier, all line loss mitigation credits should be valued at 2.37% of the power provided.

Although not specifically taking issue with the remainder of those issues, the Staff reasserted its belief that although RECs resulting from the operation of QFs that have signed onto the standard offer tariff should go to the company, their application (i.e., whether they are assigned to the utility or the QF) should be open for discussion between Consumers and the QF whenever a negotiated contract is being worked out instead.

As for the IPPC, it contends that all potential credits (related to transmission, line losses, environmental compliance, and hedging) for QFs that are connected at low voltage levels should be factored into the avoided cost paid to those facilities. This should, the IPPC continues, apply equally to all QFs providing power pursuant to the standard offer tariff, as well as those with negotiated contracts for 20 MW or less.

Finally, it appears that both the ELPC and the GLREA agree that all of the miscellaneous avoided cost components mentioned by Consumers should be included in the computation of the rates applied to QFs operating in the utility's service territory. Moreover, with regard to the ELPC, at least, it believes that it would be wise for the Commission to establish a separate process designed specifically to assess and establish the level of each of these components.

Based on the evidence presented in this case, the arguments offered by the parties, decisions stated above, and general logic, it is clear that the miscellaneous avoided costs or benefits provided by reduced transmission costs, line loss mitigation, reduced carbon emissions, lowered environmental compliance costs, and the hedging value accrued due to Consumers' use of QF-produced power, should all generally be included in the calculation of the utility's avoided costs. As for the specific proposals offered by the parties, the only two with which the ALJ disagrees are (1) permanently adopting 2.37% as the line loss credit to be applied to each and every QF, as Consumers suggests, without requiring that the issue be revisited as part of the biennial review process or subjected to negotiation, and (2) the Staff's continued suggestion that all REC credits arising from QFs that operate under the standard offer tariff be automatically transferred to the utility.

With regard to the first area of disagreement, it seems logical that any QF built near a source of significant electric consumption (i.e., a city, town, village or reasonablysized commercial/industrial facility) may well surpass the 2.37% average reduction in line losses currently computed and proposed by the utility. In those situations, that QF could deserve being granted the actual line loss savings that its existence and operation create. With regard to this rejected proposal, the ALJ again finds that the average line loss credit (of 2.37%) be initially applied to QFs that sign the standard option agreement, should be reassessed in Consumers' next biennial review, and should be an area of potential negotiation for QFs that elect not to take advantage of the standard option contract. As for the second area of disagreement, and as expressed above, RECs should generally flow to the QF, unless it chooses to negotiate away any such credits. Again, this conclusion is consistent with the FERC's ruling in the Windham Solar case.

F. "Standby Working Group" and "Biennial Review" Issues

As noted earlier in this PFD, the Staff points out that the recent enactment of Act 341 requires the Commission to conduct a hearing every five years for Michigan-based utilities that, among other things, includes an assessment of whether (1) the rates paid to QFs located in that utility's service territory are just and reasonable, as well as in the public interest, as defined by PURPA, and (2) the prices assessed by the utility to those QFs for maintenance, backup, interruptible, and supplementary power--or for any other services--are cost-based, just and reasonable, and non-discriminatory.

As also noted above, the Staff suggests that the current proceeding should, for the sake of expediency, be viewed as qualifying as the first 5-year review for Consumers under Act 341 because this case is dealing with all of Consumers' PURPA-related issues. Moreover, the Staff points out that while the current proceeding was focused on the company's PURPA-based issues, a Standby Rate Working Group established in an ongoing case regarding the utility (namely, Case No. U-17735) is already dealing with the other issues mentioned above. See, Staff's reply brief, pp. 9-10. Therefore, the Staff essentially proposes that the Commission let these two cases run their course, and then adopt their results as those that would otherwise be necessitated by the initiation of a specific, stand-alone, Act 341 case. The other option, according to the Staff, would be to simply hold all of the determinations required by Act 341 in abeyance until the filing of Consumers' next rate case, assuming one is filed within the next five years.

None of the parties to this case appears to disagree with the Staff's suggested approach to use a combination of the resolutions of the present case and that currently underway in Case No. U-17735 as a means of resolving all issues related to Act 341, although the ELPC had one related request. Specifically, it asks that, in the course of the next biennial review (as well as with all subsequent reviews involving Consumers), the Staff should be directed to prepare and submit "a value-of-solar study to begin quantifying a technology-specific avoided cost" for distributed, solar-produced, electric generation. ELPC's initial brief, p. 26.

In light of (1) the logic of the Staff's suggestion to use both the results of this case and the resolution of the issues currently being addressed by the Standby Rate Working Group in Case No. U-17735 to satisfy the requirements set forth in Act 341, and (2) the lack of reasonable opposition to the request of the ELPC to have the Staff look more closely into the value of adding distributed solar energy as a source of power in the context of Consumers' next biennial review, the ALJ finds that each of those positions should be adopted. It is therefore recommended that the Commission approve their implementation in this case.

IV.

CONCLUSION

Based on the foregoing discussion and findings, the ALJ concludes that, with regard to the avoided capacity cost rate for Consumers, the Commission should do the following: (1) adopt the Staff's proposal to set the rate for QFs located in Consumers' service territory at a level that would be equal to that of an NGCT, but that would also, in so doing, take into consideration the effects of ZRCs used by MISO when evaluating the utility's actual capacity needs in the future, albeit only as they pertain to intermittent energy sources, such as wind- and solar-powered generating units; (2) require that any electric capacity that the company should need during its next 10-year planning horizon should first come from either existing or new/proposed QF suppliers, that existing QFs supplying power to Consumers be paid the full standard offer tariff rate--as opposed to the PRA--following the end of their current contracts, and that any new QFs would be paid in accordance with the PRA; and (3) as suggested by Cadillac and the MPLP, and concurred with by other parties to this proceeding, determine that the rates established in this case will not apply to, or in any way alter, the rates set in existing QF agreements, but would only apply to new QF contracts (again, regardless of whether they arose by way of use of the standard offer tariff or by way of a negotiated agreement).

With regard to the issues relating to the PURPA-related avoided energy costs for QFs located in Consumers' service territory, the ALJ suggests that the Commission concur with the jointly-supported proposal (initially offered by the Staff, but subsequently agreed to by the GLREA and the ELPC) to give QFs the option of either: (1) adopting energy prices that are based on the actual LMP, (2) using the then-existing forecasted

LMP price over the term of those contracts, or (3) accepting a new proxy price based on the forecasted variable energy cost of a NGCC plant, along with an ICE adder. In so doing, and as discussed above, the ALJ urges the Commission to adopt Cadillac's request that no alteration be made to the energy charges currently paid to QFs in Consumers' service territory, at least until the expiration of their existing contracts, and that the Staff's three-option methodology for setting energy costs/prices only apply to QFs offering 20 MW or less.

As for the standard offer tariff, the ALJ finds that the Commission should approve and implement the seven changes proposed by the Staff that were previously found, at least by the ALJ, to be both beneficial and fair to all interested parties. This would include the uncontested suggestion that, as part of the biennial review, the standard offer could be updated at that time. As for the two rejected proposals, the ALJ suggests (with regard to the first) that the available term of any standard offer tariff made available to a QF be extended to 20 years, if the QF so desires, in order to increase the potential availability of receiving all necessary financing. The ALJ further urges that (with regard to the second rejected proposal), the Commission conclude that the RECs created by the operation of a QF either not be assigned to Consumers, or--at a minimum--the benefit relating to those RECs be fully recognized in the computation of the avoided cost offered to the QF in question, obviously at the QF's discretion. See, ELPC's reply brief, p. 9. Essentially, this recommendation would mean that RECs would stay with the QFs that create them, or, alternatively, be fully recognized as a portion of the avoided cost figure applied to the QF in question during the course of contract negotiations, if such discussions actually are undertaken.

In addition, and at the risk of sounding repetitive, the ALJ finds that the parties should be directed to specifically address (if they so choose) the prudence of increasing the potential cap on the standard offer tariff to 20 MW, which the ALJ finds to be the most reasonable limitation to be adopted in this proceeding. Moreover, the ALJ suggests that the Commission adopt the concurrent proposal by the Staff and Consumers to consider, in future cases, looking at the utility's capacity needs over a 10-year forecasting horizon, and then using the first 5 years of that period's analysis as the primary focus for making any definitive, structured capacity need determinations.

Also, and as addressed above, the ALJ believes that (although supporting the other seven proposals offered by the parties regarding the inclusion of the avoided costs and benefits from reduced transmission costs, line loss mitigation, reduced carbon emissions, lowered environmental compliance costs, and potential hedging value when calculating the company's full avoided costs), there are two areas that should not be considered by the Commission in making the avoided cost calculation regarding Consumers. These consist of the utility's request to permanently adopt a line loss credit of 2.37% for application to all QFs, as well as the Staff's request that all REC credits for QFs operating under the standard offer tariff should automatically be transferred from those QFs to the company.

As a result, the ALJ recommends that the Commission agree with the findings, conclusions, and suggestions set forth above, and thus issue an order that is consistent with them. Finally, the ALJ states that any other matters that may have been raised by the parties to this case, but that have not been specifically addressed in this PFD, were found to be unnecessary for the resolution of the specific issues set forth by the Commission in the context of this proceeding.

MICHIGAN ADMINISTRATIVE HEARING SYSTEM
For the Michigan Public Service Commission

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Mark E. Cummins
Administrative Law Judge

March 10, 2017

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

STATE OF MICHIGAN	)	
	) SS.	Case No. U-18090
County of Ingham	)	
	)	

P R O O F O F S E R V I C E

Carol M. Casale being duly sworn, deposes and says that on March 10, 2017, she served a copy of the attached Proposal for Decision via email to the persons as shown on the attached service list.

Carol M. Casale

Carol M. Casale

Subscribed and sworn to before me
This 10th day of March, 2017.

Lisa Felice

Lisa Felice
Notary Public, Eaton County
My Commission Expires April 15, 2020

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